Letter ID	Commenter Name	Commenter Org.
00513	[No name provided]	Individual
0527	Ex. 6 Personal Privacy (PP)	Clean Water Alliance
00528		Aligning for Responsible Mining

00546	Ex. 6 Personal Privacy (PP)	Oglala Sioux Tribe
00553		South Dakota DENR
07445		Individual

07460 (5/8 Rapid City hearing)	Ex. 6 Personal Privacy (PP)	Individual
07461 (5/9 Rapid City hearing)		Individual

07461 (5/9 Rapid City hearing)	Ex. 6 Personal Privacy (PP)	Individual
07461 (5/9 Rapid City hearing)		Individual
07642 (Hot Springs hearing)		Individual

Text
Class V wells are for non hazardous waste disposal What non hazardous material will be injected in these class V wells?
Another process issue is that EPA has gone through all sorts of contortions in its Fact Sheet on the Class V application in an attempt to define what is clearly a Class I well as a Class V well. The disposal would clearly take place above a USDW, the Madison formation, which is a large aquifer of broad use in the Black Hills. It is used by, among others, Edgemont and Rapid City. The EPA justifies its labeling of Class I wells as Class V wells by treating them as Class I wells for construction and monitoring purposes and by requiring the company to treat the injectate until it is "at or below radioactive waste standards" (Class V Draft Area Permit Fact Sheet, p. 8). The fear of many people in the area, as expressed in the public hearings, is that this is not sufficient. and our water would become irretrievably contaminated. [...] Next, deep disposal well integrity should be tested at least once per year, not as infrequently as every 5 years, as EPA suggests in the Class V Fact Sheet (p. 56). And injectate should be monitored and analyzed regularly, as the characteristics of wellfields will differ, and as the functioning of the RO system may also vary in effectiveness. Records should be maintained until at least five years after the end of the project, in case problems develop over time, not for as little as three years, as the Fact Sheet suggests (p. 59). Similarly, EPA calculations indicate that "the pressure within the Minnelusa injection zone resulting from injection activity is **not** [bold in original] below the critical pressure needed to move fluids out of the Minnelusa injection zone into the Madison Formation" (p. 28). The EPA correctly requires the company to recalculate in light of this fact, but must also hold firm if the resulting injection rates are even near the critical pressure, with the potential result that the permit would not be granted. Again, it is critical to protect the Madison aquifer, and the nature of the upper portion of that aquifer is particularly concerning due to the presence of rapid water movement.
3. COMMENTS SPECIFICALLY RELATED TO DRAFT CLASS V UIC AREA PERMIT A. Powertech is required to demonstrate that the injectate will be contained within the injection interval by confining zones above and below. The upper confining zone is identified as the Opeche shale which overlies the Minnelusa Fm. The lower confining zone is identified as the lower part of the Minnelusa Fm. **Calculations performed by EPA staff indicate that the injection induced pressure within the injection zone will exceed the critical pressure needed to move waste fluids into the underlying Madison USDW for a distance of 3.5 miles from DW1 and 2.5 miles from DW-3. This means that there is a significant potential for waste fluid injectate to migrate downward through natural geologic pathways (faults, fractures, high permeability zones) or anthropogenic features (abandoned oil/gas wells). There is significant disagreement on this between EPA and Powertech based on very different calculations of the critical pressure.** **There is also significant uncertainty regarding the porosity of the injection zone, the elevation of the potentiometric surface of the Madison Fm. and the effect of pumping by two proposed Madison water supply wells. These data are necessary for calculating the distance over which the injection-induced pressure exceeds the critical pressure needed to move waste fluids downward to the Madison. To be conservative the Area of Review should extend at least 3.5 miles from each proposed class V well.** Currently the lack of hydrologic data for the Minnelusa Fm. injection zone and, especially the Madison Fm. results in uncertainty that is too great and does not support a decision that there is an adequate lower confining zone. It may also mean that more than 4 injection wells will be required to limit injection rates and pressures. B. Lack of Site Specific Data. Calculations were made to estimate the radius of fluid displacement, which is an indication of how far from the injection well the waste fluid will move. The calculations were based on a simple model which consider only porosity and thickness of the injection zone. **Powertech used a porosity value of 21% and EPA used a porosity value of 10%. Neither are based on site specific data**. These analyses did not consider transport of the waste fluid plume by ground water flow. The waste fluid plume will not be static –but will migrate in a downgradient direction once it is emplaced in the injection zone. C. EPA is relying on data that will be obtained from drilling and testing the two proposed Madison water supply wells (***which have not been approved by SD DENR***) and drilling and testing the Class V wells. EPA is also relying on data on formations underlying the Minnelusa from well DW-1 ***if*** it is drilled to the base of the Deadwood Fm. as Powertech indicated in the Class V permit application ***(unclear if Powertech still plans to do this).*** **This results in a difficult problem if Powertech cannot obtain any data hydrologic/ geologic on the Madison USDW or if data obtained indicate that the proposed injection zone does not meet the criteria specified in UIC regs. It would be very difficult for EPA to deny a permit once the wells are drilled and completed. This means that more data is needed before a permit is issued.**

[...]

G. **Class V fact sheet. What about the arsenic, barium, cadmium, chromium, lead, mercury, selenium and silver?**

The EPA Document states:

7.8.1 Hazardous Waste Permit Limits

The Area Permit requires the injectate to be below the concentrations for the hazardous waste toxicity characteristic limits found at 40 CFR § 261.24 Table 1. The Table 1 constituents that could be expected in the injectate are the following metals: arsenic, barium, cadmium, chromium, lead, mercury, selenium and silver. The Area Permit requires that the injectate samples be analyzed quarterly for these metals. Arsenic and selenium are present in the uranium ore deposit mineralogy. The hazardous waste permit limits the injectate must meet are listed in Table 19.

Permit SD52173-00000 51 Dewey-Burdock Class V Draft Area Permit Fact Sheet

USNRC, NUREG-1910, Vol. 1, GEIS, Section 2.7.2 describes typical liquid waste from ISR facilities:

Liquid wastes from ISL facilities are generated during all phases of uranium recovery; construction, operations, aquifer restoration, and decommissioning. Liquid wastes may contain elevated concentrations of radioactive and chemical constituents. Table 2.7-3 shows estimated flow rates and constituents in liquid waste steams for the Highland ISL facility. Liquid waste streams are predominantly production bleed (1 to 3 percent of the process flow rate) and aquifer restoration water. Additional liquid waste streams are generated from well development, flushing of depleted eluant (the fluid that removes uranium minerals from the resin) to limit impurities, resin transfer wash, filter washing, uranium precipitation process wastes (brine), and plant wash down water.

Table 19. Hazardous Waste Concentration Limits for Class V Deep Disposal Wells

Constituent Total Metals Concentration Limit (mg/L)

Arsenic 5.0

Barium 100.0

Cadmium 1.0

Chromium 5.0

Lead 5.0

Mercury 0.2

Selenium 1.0

Silver 5.0

7.8.2 Radioactive Waste Permit Limits

The Area Permit requires that the injectate be treated to decrease radionuclide activities to levels below the established limits for discharge of radionuclides to the environment, which are listed in 10 CFR Part 20, Appendix B, Table 2, Column 2. These limits are presented in Table 20. Waste streams containing radionuclides below these regulatory limits are not classified as radioactive waste per UIC regulations.

The radioactive constituent limits included in Table 20 are the limits set in Table 16 of the Area Permit that injectate will have to meet. Liquid wastes will be treated to achieve uranium effluent limits in the ion-exchange columns. It is not anticipated that thorium-230 and lead-210 will be present at concentrations above the limits; however, if concentrations are above the limits, the effluent will be treated as necessary to satisfy the Table 16 limits. Radium-226 will be treated in radium settling ponds by adding barium, which will cause the radium to precipitate out of solution.

Table 20. Radioactive Effluent Limits for Class V Deep Disposal Wells.

Radionuclide Effluent Limits

10 CFR 20 App B, Table 2, Column 2 µCi/ml Permit Limit pCi/l

Lead-210 1.00x10-8 10

Polonium-210 4.00x10-8 40

Radium-226 6.00x10-8 60

Uranium (Natural) 3.00x10-7 300

Thorium-230 1.00x10-7 100

EPA and Powertech documents continues to rely on Powertech's intent to dispose of its liquid chemical waste via a Class V underground injection control permit. However, the disposal of waste, and particularly radioactive waste, below the lower-most aquifer that serves as an Underground Source of Drinking Water (USDW), as proposed here, is not a Class V activity. Rather, such disposal is a Class I underground disposal well. Compare, 40 C.F.R. § 144.80(a) (Class I – deep injection) with 40 C.F.R. § 144.80(e)(Class V – shallow injection).

Further demonstrating this fact is the SD DENR which classifies any well that proposes to be used for injection of either hazardous or non-hazardous liquid waste, or municipal waste, as a Class I UIC well. Importantly, the State of South D 9 akota specifically and unambiguously precludes operation or construction of any Class I UIC wells within its borders. Indeed, the applicable regulatory provision is even broader, stating in its entirety: "Class I and IV disposal wells prohibited. No injection through a well which can be defined as Class I or IV is allowed." S.D. Admin. R. § 74:55:02:02 (emphasis added). This is a significant issue, which the EPA analysis must address.

On December 8, 2016, Powertech expressed concern that removing the Deadwood Formation as an option for injection of treated ISR waste fluids would greatly diminish the capacity for waste fluid disposal. A few days later, Powertech withdrew its request to inject into the Deadwood Formation.

Therefore, based on Powertech's own statements, its proposed capacity for waste fluid disposal is greatly diminished which increases the likelihood of land application. However, the Application does not address the cumulative impacts of land application of toxic waste fluid including selenium which is highly toxic to people and wildlife. These impacts require a full and complete analysis.

Lastly on this point, the EPA and Powertech documents continues to rely on Powertech's intent to dispose of its liquid chemical waste via a Class V underground injection control permit. However, the disposal of waste, and particularly radioactive waste, below the lower-most aquifer that serves as an Underground Source of Drinking Water (USDW), as proposed here, is not a Class V activity. Rather, such disposal is a Class I underground disposal well. Compare, 40 C.F.R. § 144.80(a) (Class I – deep injection) with 40 C.F.R. § 144.80(e) (Class V – shallow injection). Further demonstrating this fact is the State of South Dakota's Department of Environment and Natural Resources, which classifies any well that proposes to be used for injection of either hazardous or nonhazardous liquid waste, or municipal waste, as a Class I UIC well. See, Chart located on the State of South Dakota's website: http://denr.sd.gov/des/gw/UIC/UIC_Chart.aspx. Importantly, the State of South Dakota specifically and unambiguously precludes operation or construction of any Class I UIC wells within its borders. Indeed, the applicable regulatory provision is even broader, stating in its entirety: "Class I and IV disposal wells prohibited. No injection through a well **which can be defined as** Class I or IV is allowed." S.D. Admin. R. § 74:55:02:02 (emphasis added). This is a significant issue, which the EPA analysis must address.

Comments on the Draft Class V Area Permit

3. Page 4, Section A.1.d - DENR recommends EPA evaluate the total dissolved solids (TDS) concentration on a well-by-well basis due to the variability of TDS concentrations in the area and to be consistent with the existing aquifer exemption process for the Class II disposal wells in the vicinity of the proposed project.

4. Page 27, Section D - DENR recommends EPA have an inspector on-site to witness the initial and ongoing mechanical integrity testing of the Class V Area Permit wells.

5. Page 27, Section E - DENR concurs with the permit limitation described in Section E - Class V disposal should only be authorized in non-USDWs (Underground Source of Drinking Water with TDS greater than 10,000 mg/L).

6. Page 28, Section K - DENR recommends EPA add a third sub-section to this section stating the permittee is prohibited from injecting waste fluids received from facilities other than from operations associated with the Dewey-Burdock Uranium In Situ Recovery Project.

7. Page 38, Section A- This section states EPA will not approve the plugging and abandonment (PA) of any Class V well until all Class III wellfields have been decommissioned by the Nuclear Regulatory Commission (NRC). DENR recommends EPA revise this section to include the authority to authorize the immediate PA of a Class V well in the event a well loses mechanical integrity or otherwise fails and threatens a USDW.

8. Page 44, Section D.11.i - Revise this section to include the following contact information for reporting oil and chemical releases to DENR. DENR Ground Water Quality Program, Spills Section, (605) 773-3296 or after hours at (605) 773-3231.

Subject: Dewey-Burdock Project Question

Greetings --

We are getting conflicting information here in the Black Hills of South Dakota, and I'm hoping you can clarify things. The topic is deep disposal wells in Fall River and Custer Counties in the general area of the Dewey- Burdock uranium mining project. I am preparing expert testimony for the draft permit process and want to be operating from accurate information.

Linsey McLean, who met with you in December, says that you indicated that there are as many as twelve deep disposal wells planned in the general area of the Dewey-Burdock project. The recently issued draft permit for the project says that there will be two to four DDWs. Are there other projects planned that we haven't heard about here yet? Or is there some other way to account for the 8 "missing" DDWs?

Thanks much for your help in clarifying things.

My second concern has to do with the aquifer restoration plan. According to Azarga/Powertech, the company proposes to restore the contaminated aquifers by treating water pumped from production wells using reverse osmosis, membranes under high pressure, thus removing 90 percent of the dissolved constituents. Restored water will then be returned to injection wells, and the RO reject, the brine, will be disposed of in the Class V wells.

The company has concluded that minimal benefit, if any, is derived from the groundwater sweep prior to deep well injection and suggests eliminating groundwater sweep as an unnecessary, ineffective, and consumptive step in the restoration process.

According to the EPA, "High pressure reverse osmosis can only be employed after groundwater sweeping, because high concentrations of contaminates during the initial stages of the restoration process tend to disrupt and rupture the RO membranes."

Ex. 6 Personal Privacy (PP) Good evening, Judge and EPA officials. My name is Ex. 6 Personal Privacy (PP) and I live in Rapid City. And I spoke yesterday, and I'd just like to clarify a comment that I made about the number of drinking water wells in the Minnelusa aquifer.

After speaking with Ken Buhler -- B, as in boy, U-H-L-E-R -- of the South Dakota Department of Environment & Natural Resources, or DENR, he said that in November of 2014, the DENR started identifying which aquifer a well draws from on their permit forms, and this means that for many wells in use it is unknown which aquifer they draw from.

Mr. Buhler said there are hundreds to thousands of domestic wells using water from the Minnelusa Aquifer. The exact number of wells is unknown at this time. However, Mr. Buhler said it is known that there are 196 appropriated water rights permits in the Minnelusa, which include municipal, commercial, industrial, and housing use.

In addition, the USGS -- that's United States Geological Survey -- Water-Resources Investigations Report 01-4119 abstract starts with this statement: "The Madison and Minnelusa aquifers are two of the most important aquifers in the Black Hills area of South Dakota and Wyoming."

The USGS Water-Resources Investigations report 01-4226 abstract begins with: "The Black Hills are an important recharge area for aquifers in the northern Great Plains. The surface-water hydrology of the area is highly influenced by interactions with the Madison and Minnelusa aquifers, including large springs and streamflow loss zones."

In Valois Shea's presentation yesterday, she mentioned that a Class V injection well permit could not be used for an aquifer that is an underground source of drinking water, if I understood correctly.

The Minnelusa is being used as a such, so I think it is safe to say that it is considered an underground source of drinking water.

The EPA's website defines an underground source of drinking water as the following: One, it supplies any public water system, which the Minnelusa does; two, the source of water contains a sufficient quantity of groundwater to supply a public water system, which it appears the Minnelusa does; three, it currently supplies drinking water for human consumption, which it sounds like the Minnelusa does; and four, it contains fewer than 10,000 milligrams of total dissolved solids, which according to USGS tables that I found online applies to most parts of the Minnelusa; and five, the source of water is not an exempted aquifer, which I believe the Minnelusa is not.
So I just wanted to update you with those findings since yesterday. And I thank you for your time.

The ability to purify the wastewater to Class V standards is not being considered. Simply putting the wastewater in a pond to air out the radon gas and then precipitating out the radium with barium chloride does not remove the other radioactive and toxic components.
The toxic metals that have been mobilized are still there. And that includes vanadium, strontium, thallium, thorium, some radioactive forms of lead, and organified uranium that has been documented to build up in recycled wastewater and is not recoverable by ion exchange. And all are radioactive as well as toxic as heavy metals in biochemistry.

This does not constitute the level of safety equal to stormwater or sewage effluent that a Class V well is limited to. If Powertech were able to clean this water to levels they boasted about in the NRC and ASLB hearing, so pure you could almost swim in it, then that water would be valuable for agriculture, irrigation, and farm use in this high, dry area of the country.

It does not meet the qualifications for a Class V UIC, not for the concentration of toxic metals and radioactivity of such.

And I want to pick up a little bit on what Ms. Ex. 6 Personal Privacy (PP) was referencing, which is the wide use of the Minnelusa aquifer for drinking water purposes.
I think it's been well documented. I would ask the EPA, how many wells have you determined through surveys to be downgradient from this Dewey-Burdock site? I know you can't answer questions tonight, but I'd like to have that in the record.
Because of this drinking water use of the Minnelusa, I would ask that the EPA require the Class V injection well wastewater to meet drinking water standards, not hazardous waste standards as is currently in the draft permits.
I did a little research and will read to you some of the numbers that I came up with. Right now, the hazardous waste concentration limit in the Class V permit, for instance, for arsenic is 5 milligrams per liter.
If you follow the maximum contaminant -- the MCL for drinking water for arsenic, it would be .01. So that's a factor of 500 times more than what's in the MCL, the primary MCL.
I could go down the list. Barium, you guys give them 100; the MCL is 2. So that's 50 times. Cadmium is 1, and then in your -- in your current limit, it's .005 MCL. So that's 200 times more than the drinking water criteria. Chromium, you gave them 5; it's .1 MCL. That's 50 times. Lead doesn't have a primary MCL, as you know, but it has -- there's a new lead rule, we've heard all about Flint. That concentration is .0015 milligrams per liter, and you guys gave them 5. So that's 3,333 times what's in the drinking water regs. Mercury, selenium, silver.
I'm wondering why uranium is not in there. I know you have a uranium radioactive standard measured in microcuries per milliliter, or whatever the units are. But there is an MCL for uranium, and it's .03. So why isn't that in the standard -- in your current concentration limit for the Class V wells?
So these are just some of my recommendations. And furthermore, I know that Powertech can meet these levels. They can treat these waters to these kinds of levels. In fact, the EPA's best available treatment, the BAT for Small System Compliance Technologies, SST -- SSCT, it can be found in your final radionuclides rule 40 C.F.R. 141.66, specifies that at least three technologies should be used in combination to achieve these low levels.
So not only should Powertech be required to use reverse osmosis, they can also -- they would also couple this with a tertiary type of treatment, including activated carbon and ion exchange.
All of these things are technologically possible, in which case we would be -- or they would be injecting drinking-water-quality water because people are drinking this water, and I think that's where this should end up.
I'm an engineer. I'm practical. I'm trying to help you guys meet the criteria. I mean, we've heard tonight and yesterday all the heartfelt -- people's, you know, we're not going to contaminate the earth, and we don't want that to happen.
But I know we have to have rules, and I'm trying to help you guys pick the right rules so that we can maintain what we need as far as drinking water quality in this area.
So thank you very much.

Present ion exchange technology will not remove organified heavy metals, including uranium. Disposal of this waste fluid should require permitting for a Class I well, not a Class V well

refer to the record of communication for this conversation

answered during public comment period

we already addressed this comment with an email

The acutal quote is "In practice, this method can only be employed after groundwater sweeping, because the high concentrations of contaminants during the initial stages of the restoration process tend to disrupt the RO membranes (Davis and Curtiss 2005)"

The quote is from *Technical Report on Technologically Enhanced Naturally Occurring Radioactive Materials from Uranium Mining Volume 2: Investigation of Potential Health, Geographic, And Environmental Issues of Abandoned Uranium Mines*
Published on-line as Vol. 2 of EPA 402-R-05-007, August 2007
Updated and printed April 2008 as EPA 402-R-08-005

The quote is found on p. AIII-9, referencing Davis and Curtiss, 2005.
Davis, J., and Curtiss, G. *Consideration of Geochemical Issues in Groundwater Restoration at Uranium In-Situ Leach Mining Facilities* Draft Report for Comment. NUREG/CR-6870, U.S. Geological Survey, Menlo Park, California. June 2005.

Ex. 5 Deliberative Process (DP)

https://www.epa.gov/sites/production/files/2015-05/documents/402-r-08-005-v2.pdf

From Dec 2013 Tech Report, 3.2.7.1 Restoration System Equipment

Restoration Reverse Osmosis System
The restoration RO system at each site will be a packaged system capable of treating approximately 500 gpm and producing a permeate stream and a reject brine. This system will include necessary pretreatment, including multi-media or sand filters and feed conditioning.

Table 1.	Draft Class V Area Permit Specific Comments and Recommended Permit Language Revisions					
Comment #	Draft Permit		Fact Sheet		Type	Comment and Recommended Permit Language Revision or Other Modification
	Page	Section	Page	Section		
1	2	I.B	---	---	E, C	**Comment:** Why are South Dakota regulations in 40 CFR § 147.2100 referenced, when those regulations are for Class II wells? **Requested Change:** Powertech suggests changing the reference to the more general 40 CFR part 147, subpart QQ or else 40 CFR § 147.2101, which pertains to Class V wells. The requested change is shown below. UIC regulations specific to South Dakota are found at 40 CFR ~~§ 147.2100~~ part 147, subpart QQ.
2	2	I.B	---	---	I, C	**Comment:** Though it is referenced elsewhere in the draft permit, a reference to 40 CFR § 144.41 is not included here. **Requested Change:** Powertech requests adding reference to 40 CFR § 144.41 as follows. This Area Permit is issued for a period of ten (10) years unless modified, revoked and reissued, or terminated under 40 CFR § 144.39, ~~or~~ § 144.40, or § 144.41.
3	4 15	II.A.1 II.I	35	5.3.4.1	R	**Comment:** Part II of the draft permit presents a regulatory process to obtain "Limited Authorization to Inject". **Requested Change:** Powertech is not aware that a Limited Authorization to Inject (LAI) is an established regulatory process, or is warranted in any way, for the proposed operation. Powertech is not aware that EPA Region 8 has included an LAI requirement for any Class V, Class I, or Class III permit and requests clarification as to why this permit requirement is necessary to protect USDWs, or, absent such clarification, Powertech requests removal of the LAI requirement as described below. The testing procedures that are included under the LAI are routinely done in many similar well permits without a separate authorization, lack any significant potential for contamination of USDWs and are done with well casing in place. Powertech requests moving the Part II, Section A.1 requirements in entirety to Section A.2 (Information to Submit to the Director to Obtain an Authorization to Commence Injection). Similarly, Powertech requests moving the Part II, Section I requirements to Part II, Section K, where they can be identified as "Logging, sampling, and testing prior to well operation."
4	4 20	II.A.1.c III.B Figure 3	---	---	I, C	**Comment:** Powertech is committed to completing Class V injection wells only into the Minnelusa Formation at this time and as such would not penetrate the Madison with drilling effort shown in Figure 3 of the draft permit. **Requested Change:** Powertech requests removal of Figure 3 in its entirety and removal of any requirement to collect Madison data from the drilling of Class V injection wells from the draft permit and fact sheet (see also comment #11). An example is provided below for Part II, Section A.1.c:

						Evaluation of the Minnelusa and Madison aquifer fluids at ~~DW. No. 1, if it is drilled to the base of the Deadwood Formation, AND at~~ the Madison water supply wells, if they are approved by the South Dakota Water Rights Program and if constructed, to confirm the injection zone formation is hydraulically isolated from the Madison aquifer at the Dewey-Burdock Project Site.
5	7	II.C Table 4	---	---	A	**Comment:** The draft permit states a "Fracture Finder" log will be run. Fracture Finder has different connotations to different people. To clarify, a micro-resistivity log would be an acceptable fracture finder log. A micro-resistivity log uses the same general principals as a normal resistivity (wireline) log, except it is a pad tool with small spacing that allows for very detailed evaluation of the wellbore face and the first 1-3 inches of the formation. It is useful to differentiate between wall cake from drilling mud, filtrate from drilling mud that has invaded the formation, and the formation fluid. It is also useful to identify zones that have significant fluid invasion (such as natural fracture intervals). For this reason, a micro-resistivity log is often referred to as a Fracture Finder log. **Requested Change:** Add "(Micro-resistivity)" after "Fracture Finder" in Table 4.
6	7-Jun 19-22	II.C Tables 3, 4, 5 Table 11 Figures 4-5	---	---	A	**Comment:** EPA has utilized casing sizes included in the permit application that was submitted in 2010. Since that time, market conditions and casing availability have changed; Powertech may elect to run larger production casing (7" OD versus 5 ½" OD stated in the permit application). The main reason that larger casing may be considered is to allow for installation of larger injection tubing, which will reduce friction loss and fluid velocity, both which will extend the useful life of the injection tubing. Installation of larger casing and/or tubing will have no impact on the protection of USDWs required under the Class V UIC permit. **Requested Change:** Update the text, tables, and figures to allow for use of 7" (or similar) production casing as dictated by technical and design requirements and market conditions. One specific text revision request is included in comment #24. Additional requested changes include but are not limited to: - Table 3: Under Cement Bond Log Due Date, change to "Prior to setting 7" or 5-1/2" casing in DW. No. 3" - Table 4: Under Due Date for all but Mud Logging, change to "Prior to setting 7" or 5-1/2" casing in DW. No. 3" - Table 5: Under Cement Bond Log Purpose, change to "Cement behind the 7" or 5-1/2" casing in DW. No. 3" - Table 5: Under Casing Inspection Log Purpose, change to "Casing quality of the 7" or 5-1/2" casing in DW. No. 3" - Table 11: Under Longstring Casing for DW No. 1 alternate and DW No. 3, change to "7" or 5 ½" - Figures 4 and 5: Change to "7" or 5 ½" Longstring Casing"
	5 12	II.B Table 2 II.E.2.a, c	32	Sec. 5.1 Table 10	R	**Comment:** The Draft permit specifies that (1) core samples shall be collected only from the lower 50 feet of the Opeche Shale and upper 50 feet of the Lower Minnelusa confining zone, rather than within the confining zones in general; (2) cores must be collected in all Class V wells; and (3) core must be collected from the Lower Minnelusa only if DW No. 1 is drilled to the Deadwood. **Requested Change:** Powertech requests that the draft permit be revised to require core from the overlying and underlying confining zones, but allow the operator to determine the core location within the respective confining zones. The 50-foot restriction in the draft permit could misrepresent the overall confining abilities of the overlying and underlying confining zones.

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This approach, where it is up the operator to determine the appropriate core point in the confining zones, is common for UIC permits throughout the country. The core analysis data and geologic information (geophysical logs, drill cuttings, and mud log) will be provided to EPA to demonstrate that (1) the cores were collected from a representative portion of the confining zones, and (2) the properties of the confining zone are adequate to provide isolation between the USDWs and the injection zone.

Further, Powertech requests the draft permit be modified to require collection of core only in the first well, rather than in each well. The overlying and underlying geologic confining units (Opeche

Shale and Lower Minnelusa) are pervasive in the Dewey-Burdock area, and the intrinsic values for the formation properties are expected to be substantially similar at different locations across the site. After drilling the first Class V well (which will include core of the confining zones), geologic logs from subsequent wells will be compared to the first well to demonstrate consistency and continuity of the geologic confining units.

Figures A-2, A-3, A-4, D-21 and D-22 in the permit application show consistent log character for the overlying confinement (**Minnekahta and Opeche Shale**) and underlying confinement (Lower Minnelusa, where logs are deep enough) over large distances (10-20 miles). New log information from the wells to be drilled at the project site will provide even more detail that will further support the regional information. Requested changes are shown below.

II.B. Collection of Drill Core in the Injection Zone and Confining Zones

1. The Permittee shall collect drill core from the injection zone, the overlying confining zone formation and the underlying confining zone while drilling the first well under this Area Permit as described in Table 2 for the reasons stated in Table 2. Laboratory data may be supplemented by data from pressure transient testing and porosity information from the BHC Sonic log.

2. The Permittee shall compare geologic logs from subsequent wells to the first well to demonstrate consistency and continuity of the geologic confining units.

3~~2~~. The information shall be included in the Injection Authorization Data Package Report for each Class V injection well.

4~~3~~. The effective porosity and permeability of the injection zone formations shall be used as the input values in the equation used to calculate decline of injection zone pressure with distance away from the injection well described in Part II, Section F.2.

Table 2. Drill Core Collection for Laboratory Testing

TYPE OF TEST
While drilling the first ~~each~~ injection well, core samples shall be collected in the Minnelusa Injection Zone.
While drilling the first ~~each~~ injection well, core samples shall be collected within the ~~lower 50 feet of the~~ Opeche Shale Confining Zone

						Samples shall be collected from the ~~top 50 feet of the~~ Lower Minnelusa confining zone while drilling the first injection well ~~DW No. 1, if the borehole is drilled to the base of the Deadwood Formation OR while drilling the Madison water supply wells, if they are approved by the South Dakota Water Rights Program~~.
						II.E.2. Core Sample Collection from Confining Zones a. During the drilling of ~~each~~ the first injection well, core samples within the ~~lower 50 feet of~~ Opeche Shale confining zone shall be collected. b. During the drilling of the first injection well ~~DW No. 1, if it is drilled down to the base of the Deadwood~~, core samples shall be collected within the ~~top 50 feet of the~~ Lower Minnelusa Formation ~~lower~~ confining zone. ~~c. If DW No. 1 is not drilled down to the base of the Deadwood, core samples shall be collected within the top 50 feet of the Lower Minnelusa Formation during the drilling of the Madison water supply wells, if they are approved by the South Dakota Water Rights Program.~~
8	6	II.C.5	---	---	A	**Comment:** The draft permit requires performance of deviation checks in a pilot hole, and then reaming the pilot hole to enlarge the diameter. **Requested Change:** The proposed Class V wells will be designed for and drilled with equipment commonly used for oil and gas wells where detailed deviation checks can be performed without the need for a pilot hole. The deviation checks discussed in 40 CFR § 146.12(d)(1) refer to a well where a pilot hole is planned, whereas no pilot hole is planned for any of the Powertech Class V wells. Powertech requests that the pilot hole requirement be removed. During drilling, deviation checks will be performed with either (1) single-shot survey tools (wireline survey tools run approximately every 1,000 feet that have an accuracy of ¼ of one degree), or (2) measurement while drilling (MWD) tools that “continuously” (every 30 feet) measure deviation to an accuracy of 1/10 of one degree). Pilot holes may be drilled in some situations where a large-diameter completion is required and very tight vertical deviation tolerances are necessary for installation of downhole pumps (e.g., municipal water supply wells where the final hole diameter is 18-36 inches and line shaft turbine pumps are used). This is a very different application from that proposed for Class V wells under this permit. A pilot hole approach would cause a large cost increase (due to drilling the pilot and subsequent reaming) and could cause hole problems due to longer exposure times for water-sensitive shales (e.g., the Morrison and Opeche). Requested changes are shown below. 5. The Permittee shall perform deviation checks on all injection well holes ~~constructed by first drilling a pilot hole, and then enlarging the pilot hole by reaming or another method~~. Such checks shall be conducted at sufficiently frequent intervals to assure that vertical avenues for fluid migration in the form of diverging holes are not created during drilling.
		II.D	21-22	3.4		**Comments:**

		Tables 6-7				Given the extensive sampling of the Fall River and Chilson throughout the project area (as documented in the draft Class III permit and Class III permit application), additional characterization of the water quality in these overlying aquifers is not necessary. Between 2006 and 2010, baseline water quality samples were collected from 30 Inyan Kara wells (in either the Fall River or Chilson or both) and 4 Unkpapa/Sundance wells within the AOR. Between 1 and 15 samples were collected from each well resulting in over 200 samples in all. Data from these samples are presented in Appendices N and O of the Class III permit application.
		II.D.2.b- h	33-34	5.3.1 Table 12		Further, sampling every zone above the injection zone is inconsistent with UIC regulations (40 CFR 144 and 146). The Class V permit application and the Class V fact sheet indicate that the Minnekahta is not an aquifer at Dewey-Burdock, so it should not be sampled. The fact sheet clearly states that in the project area there is no evidence of porosity in the Minnekahta and that regionally, it is only an "aquifer" near surface where dissolution has occurred (p. 21). Given this evidence, there should not be a requirement to test the Minnekahta. This requirement is inconsistent with data provided in the permit application. With regard to the Minnelusa sampling (for each Class V well), Powertech requests: (1) sampling be based on field parameters that indicate formation fluid as determined in the field; (2) duplicate analyses of two fluid samples be performed (from the same sampling run); (3) bottom-hole pressure (indicative of potentiometric surface) will be recorded in the same 1-hour pressure monitoring period; (4) use of geophysical log data to calculate formation water salinity (indicated by NaCl concentrations) for the Fall River, Chilson, Unkpapa/Sundance and Minnelusa in all Class V wells; and (5) sampling be conducted "as appropriate given the tools available" as detailed in Comments #32 and 33.

9	9-Jul				R	It is likely that the final Minnelusa formation water samples will be collected by **swabbing through tubing after the production casing is installed and the casing has been perforated.** The workover rig will install a work string (e.g., 2 7/8" tubing) and a work packer will be set above the top Minnelusa perforation. Swab cups will be installed on a swabbing line run from the surface and into the injection tubing to a depth commonly on the order of 1,000 to 2,000 feet. As the swab line is pulled back up through the tubing, formation fluid will be drawn up into the tubing, and eventually to the surface. The swabbing process is performed repeatedly so that completion fluid and near-wellbore filtrate are removed from the well, followed by formation fluid. The swab fluid parameters (temperature, pH, conductivity) will be measured and evaluated to determine when true formation fluid (as compared to drilling mud filtrate) has been recovered. Once formation fluid is present at the surface, duplicate fluid samples will be collected for the required fluid analyses. **Requested Change:** Powertech requests the overlying sampling zone include only the Unkpapa/Sundance (in the first Class V well only). Powertech requests the ability to use, as an alternative, nearby existing well data and data from any new wells which may be in place at the time of drilling of the Class V well to provide water quality data on the Unkpapa/Sundance aquifer. See also comments #4 and #11 regarding Madison aquifer data collection. Requested changes are shown below.

Table 6. Aquifers to be Tested during Injection Well Drilling

Well Drill Hole
DW No. 1
DW No. 3
~~DW No. 1, if it is drilled to the base of the Deadwood Formation AND the Madison water supply wells, if they are approved by the South Dakota Water Rights Program.~~

Table 7. Formation Testing Program

TYPE OF TEST
Isolate each aquifer specified in Table 6 and measure the potentiometric surface elevation of each aquifer specified in Table 6 as it is intersected by the wellbore
Aquifer fluid sampling and analysis: A minimum of two (2) fluid samples shall be collected from each aquifer specified in Table 6 for analyses of the parameters in Table 8
TDS evaluation of the injection zone based on a minimum of two (2) fluids samples from the Minnelusa injection zone according to the requirements under Part II, Section D.2.f and g.
Further characterization Minnelusa Injection Zone with respect to Bicarbonate, Calcium, Carbonate, Chloride, Fluoride, Magnesium, Potassium, Sodium and Sulfate concentrations. Report results as mg/L, milliequivalents per liter and plot as STIFF diagram show in Figure 2.
Characterization of the Madison Formation ~~at DW No. 1, if it is drilled to the base of the Deadwood Formation AND~~ at the two Madison water supply wells, if they are approved by the South Dakota Water Rights Program and if they are constructed, with respect to Bicarbonate, Calcium, Carbonate, Chloride, Fluoride, Magnesium, Potassium, Sodium and Sulfate concentrations. Report results as mg/L, milliequivalents per liter and plot as STIFF diagram show in Figure 2.

					Measurement of additional parameters in the Madison aquifer required for updating the drawdown model of the Madison aquifer potentiometric surface described in Section 4.0 of the Report to Accompany Madison Water Right Permit Application submitted to the DENR Water Rights Program using site specific data, if the Madison wells are constructed.
					Initial Temperature Survey Log[3]
					2. Aquifer Fluid Sampling Requirements b. Before aquifer sample collection, each aquifer specified in Table 6 shall be isolated within the drill hole to prevent inflow of groundwater from other aquifers. c. Once the potentiometric surface for each isolated aquifer has been allowed to stabilize for 30 minutes, the Permittee shall collect three potentiometric surface elevation measurements a minimum of 15 minutes apart. After the potentiometric surface elevation measurements have been recorded, fluid samples shall be collected from each aquifer specified in Table 6 using the procedures in Part V, Section D.1.b and c of this Area Permit. ~~d. If the potentiometric surface of Minnekahta Formation is not above the top of the formation, the Permittee is not required to collect any fluids samples from the Minnekahta Formation. If the potentiometric surface of the Minnekahta aquifer fluid is above the top elevation of the formation, then the Permittee shall collect aquifer fluid samples to analyze for TDS and the other constituents in Table 8. If the Minnekahta Formation is not able to sustain pumping rates necessary for representative aquifer fluid samples to be collected, then the Permittee shall document sampling efforts, but is not required to collect fluids samples from the Minnekahta Formation.~~ ~~d~~e. A minimum of two fluid samples from each aquifer specified in Table 6 shall be collected as appropriate given the tools available. ~~The second sample shall be collected after one drill stem volume of groundwater has been removed after the collection of the first sample.~~ ~~e~~f. The two fluid samples from each aquifer specified in Table 6 shall be analyzed for the analytes listed in Table 8 using the analytical methods shown. Equivalent analytical methods may be used after prior approval by the Director. Analytical results shall be reported in the units listed in Table 8. ~~g. In addition to the two samples collected under Part II, Section D.2.f, a minimum of three more samples shall be collected from the injection zone aquifer and analyzed for TDS only. One drill stem volume of groundwater shall be removed between the collection of each sample.~~[4] ~~f~~h. The Permittee shall include the following information in the Injection Authorization Data Package Report submitted to the Director: i. Methods for aquifer isolation; ii. Sample collection methods; iii. Methods for insuring fluid sample is representative of the aquifer conditions; and iv. Methods for drilling fluid tracer sampling, field testing and analysis.
					Comment:
					The draft permit requires use of a tracer (typically ammonium nitrate) to differentiate between drilling mud/filtrate and formation fluid. When the permit application was submitted (2010), it was common to use ammonium nitrate and it could be readily obtained. Since that time, it has become difficult to obtain due to Homeland Security concerns. Further, as far as Powertech is aware, the vast majority of sampling for Class V and Class I wells throughout the country has been conducted without the use of a tracer, and fluid samples from those wells have been approved by EPA and various state agencies. Requested Change:

10	9	II.D.2.a	33	5.3.1	R, A	Powertech requests this permit requirement for a drilling mud tracer be removed and that this determination can be made using field sampling parameters and through observation of these parameters until they reach stability per Table 14. Measurement of field parameters has been proven to be sufficient to demonstrate that representative samples of formation fluid are obtained. The requested change is indicated below. The requirement in Part II, Section D.2.c to collect samples according to the procedures in Part V, Section D.1.b and c will necessitate measurement of field parameters without having to make additional modifications to address this comment. 2. Aquifer Fluid Sampling Requirements ~~a. The drilling program for each well shall include the addition of a tracer in the drilling fluids. The tracer used for this purpose shall be such that the Permittee is able to analyze for the presence of the tracer in aquifer fluids samples using field testing methods. The tracer shall also be included as an analyte for laboratory testing of formation fluids to verify that no drilling fluid residual is present in the formation fluid samples.~~
11	4 5 8 11	II.A.1.c Table 2 II.C.3 Table 7	16 17 33-35	3.3.1 3.3.2 5.3.1 Tables 12&13	A	Comment: The Draft permit requires that Powertech characterize the Madison (which underlies the Lower Minnelusa confining zone and the Minnelusa injection zone) if DW No. 1 is drilled to the Deadwood, and in future water supply wells drilled under a South Dakota Water Rights permit. The confinement between the Minnelusa and Madison is clearly evident in geologic cross sections provided in the permit application and discussion found in the South Dakota DENR Report to the Chief Engineer on Water Permit Application No. 2685-2 (Exhibit 001). In the Dewey-Burdock Project area, there is no question about the continuity of the Lower Minnelusa confining zone that will isolate the Minnelusa injection zone from the Madison. **Requested Change:** As described in comment #4, Powertech requests removal of any requirement to collect Madison data from the drilling of Class V injection wells. In reference to potential Madison wells, Powertech requests that in all instance where the terms “if they are approved by the State of South Dakota” be further modified to “if they are approved by the State of South Dakota and if constructed”. This would not necessitate the construction of the Madison wells as a condition of the Class V permit. Due to the requirement to conclude the State of South Dakota hearing prior to Madison well construction, Powertech would not want installation or operation of the Class V wells contingent on approval of a State of South Dakota water rights permit.

	11	II.E.1.d		12&13 5.3.3		Powertech anticipates that it will drill one or more Madison wells within the project area, and for any wells completed will collect data as listed in this section. An example of the requested text change for Part II, Section A.1.c is provided below (see also comment #4, which requests moving the Part II, Section A.1 requirements). **II.A. Injection Authorization Data Package Report** **1. Information to Submit to the Director to Obtain a Limited Authorization to Inject for Testing Purposes** For each injection well, the Permittee shall provide the following information, further described in Sections B through H, to the Director for evaluation. After evaluating the information, the Director will determine if it is appropriate to issue a written Limited Authorization to Inject to authorize the Permittee to commence injection activity for testing purposes only. c. Evaluation of the Minnelusa and Madison aquifer fluids ~~at DW. No. 1, if it is drilled to the base of the Deadwood Formation, AND~~ at the Madison water supply wells, if they are approved by the South Dakota Water Rights Program and if they are constructed, to provide additional confirmation that the injection zone formation is hydraulically isolated from the Madison aquifer at the Dewey-Burdock Project Site.
12	8 13	II.D Table 7 II.E.3.b.i II.F.2.a	31	4.4.4	C	Comment: Since the Class V permit duration is 10 years, it would be appropriate to model the drawdown in the Madison aquifer for 10 years rather than 12 years as required in the permit. A shorter duration for drawdown modeling is also warranted because the drawdown in the Madison is expected to be minimal with little change over time (Exhibit 001 at 9-10). Similarly, it would be more appropriate to calculate the injection zone formation pressures resulting from 10 years of injection activity rather than 12 years. Requested Change: In Table 7 and elsewhere, Powertech requests changing the modeling requirement for the Madison aquifer from 12 to 10 years. Powertech also requests removing the requirement to submit this information prior to receiving a limited authorization to inject and revising this to be submitted with a request for the final authorization to inject. Powertech requests revising Part II, Section E.3.b.i to remove the requirement for testing of the Madison aquifer should these wells not be approved by South Dakota DENR or not be constructed. Representative requested revisions are provided below. **II.E.3.b. Calculation of Potentiometric Surface Drawdown at the Madison Water Supply Wells** i. ~~After the testing of the Madison aquifer has provided the information on the potentiometric surface and other parameters required, t~~The Permittee shall generate a drawdown model of the change in the potentiometric surface of the Madison aquifer that can be expected to result from 102 years of pumping the Madison aquifer at each of the Madison water supply wells. If available, the drawdown model shall use information on the potentiometric surface and other parameters for the Madison aquifer from Madison water supply wells at the Dewey-Burdock Project Site. Otherwise, regional data sources shall be used. **II.F. Injection Zone Pressure and Maximum Injection Rate Calculations** **2. Calculation of Injection-Induced Injection Zone Pressure** a. For each injection well, the Permittee shall calculate the injection zone formation pressures resulting from 1 0~~2~~ years of injection activity at the injection rate needed to dispose of the maximum anticipated volume of treated ISR waste fluids versus distance away from each injection well. Cumulative effects of injection from multiple wells shall be considered as applicable.

13	12-Nov	II.E.1.e	17	3.3.2	A,R	**Comment:** The Formation Integrity Test (FIT) requirement is unnecessary and could cause impairment of the lower confinement due to testing to or above fracture pressure. **Requested Change:** As discussed previously, Powertech is committed to collection of core from the Lower Minnelusa in the first well. Analysis of that core, combined with geophysical logs across the Lower Minnelusa, will provide adequate demonstration of the integrity of the Lower Minnelusa confining zone. Lab testing of permeability from cores is superior to results obtained by FIT because it represents an actual measurement of the formation as opposed to indirectly measuring through FIT. The suitability of the Lower Minnelusa as a confining zone is also evidenced by regional hydrogeologic data collected by South Dakota DENR observation locations, as referenced in the fact sheet, and is supported by South Dakota DENR (Oil and Gas Program) who authorized the Barker Dome Class II injection wells completed in the Minnelusa and located immediately northeast of the project area. The permit file for the Ozark #3 Coffing Class II injection well, which is 3.5 miles east-northeast of the project area, is provided as Exhibit 006. Powertech requests removing the draft condition in Part II, Section E.1.e.
14	10 33	II.D Table 8 V.D.2 Table 16	35	Table 12	I,C	**Comment/Questions:** a. Are analyses for metals and radionuclides total or dissolved fractions? b. Why are the analytical methods different from those listed in the draft Class III permit (e.g., alkalinity, bicarbonate, sulfate, etc. have different methods in Table 8 of the draft Class III permit)? c. What would be the process for obtaining approval of alternate analytical methods? **Requested Change:** a. In Tables 8 and 16, metals and radionuclide samples should be analyzed for dissolved fractions to provide analytical results that represent the soluble (mobile) metals rather than suspended (particulate) metals. Dissolved analyses generally are preferred for most RCRA, CERCLA, and SDWA programs and consistent with permit requirements for UIC wells in other EPA regions and states. This would also be consistent with NRC requirements under the approved license, SUA-1600, for the Dewey-Burdock Project. b. In Table 8, Powertech requests that analytical methods be changed to be consistent with the Class III permit, Table 8. This would also make the laboratory analytical methods consistent with NRC license requirements (specifically with Table 6.1-1 of the approved NRC license application). This will bring a consistency for data collected across the project. Further, Powertech request that total analysis may be left as an alternative method if needed.

15	13	II.F.1	33 41	5.3.1 Table 12 6.0	A,R	Comment: The requirement for determination of the potentiometric surface for all overlying aquifers is unwarranted, especially given that the critical pressure rise calculation is only required for the Unkpapa/Sundance (first overlying) aquifer. Requested Change: Powertech requests that this condition be limited to the first overlying aquifer (Unkpapa/Sundance). Please see comment #9 regarding the Minnekahta formation. Potentiometric data for the Inyan Kara and Unkpapa/Sundance aquifers have already been collected through existing well data. Powertech requests the ability to use, as an alternative, nearby existing well data and data from any new wells which may be in place at the time of drilling of the Class V well to provide potentiometric data on the Unkpapa/Sundance aquifer. Mapping of the potentiometric surfaces for the Inyan Kara aquifer, represented for the Fall River and Chilson, are presented in the Figures 5.2 and 5.3, respectively, of the Class III permit application. These potentiometric surface maps are based upon a number of observations and well locations and are mapped across the well sites for DW No. 1 and 3. In addition, potentiometric surface data for the Unkpapa/Sundance aquifer is presented in the Class III permit application (Figure 2.5 in Appendix J). Requested changes are provided below. **II.F. Injection Zone Pressure and Maximum Injection Rate Calculations** **1. Calculation of Critical Pressure Rise in the Minnelusa Injection Zone** After the depths have been determined to the top and bottom of the injection zone and the Unkpapa/Sundance ~~each~~ aquifer at each injection well location based on drillhole log, and the potentiometric surface ~~s~~ has~~ve~~ been measured for the Unkpapa/Sundance ~~each~~ aquifer intersected by the injection well, the Permittee shall calculate the critical pressure rise that is needed within the injection zone to move fluids into a USDW along a hypothetical pathway through the confining zone. For the Minnelusa injection zone, this would be the critical pressure rise needed to move injection zone fluids into the Unkpapa/Sundance and Madison USDWs, respectively, at DW No.1 and DW No. 3. Representative potentiometric surface data for the Unkpapa/Sundance and Madison aquifers from wells within the Dewey-Burdock Project Site may be used, and regional data may be used for the Madison aquifer if the Madison water supply wells are not constructed.
16	13	II.F.2.c	26, 30	4.4.2.1 Table 9	I, R	**Comment:** There is no evidence whatsoever that (a) oil/gas wells or (b) the Dewey Fault are potential conduits for flow from the Minnelusa injection zone to the first overlying aquifer. This characterization is supported by the permit application and the South Dakota DENR Report to the Chief Engineer on Water Permit Application No. 2685-2 (Exhibit 001 at 9, paragraph 1). Powertech believes that EPA may have misinterpreted the data provided in the application. Requested Change: Reference to either oil/gas wells or the Dewey Fault as conduits for vertical flow out of the injection zone within the project area should be removed because of the following: a. Earl Darrow #1 was properly plugged and abandoned with records included in the application. b. There are no data supporting the Dewey Fault as a conduit to flow between the aquifers. c. In the Class V fact sheet, Madison/Minnelusa well pairs at Hell Canyon shown on page 20 are 2 miles northwest of the Dewey Fault. These wells exhibit a difference in potentiometric surface, indicating confinement and hydrogeologic isolation between the Madison and Minnelusa in proximity to the fault. Further, the potentiometric surface of the Madison is well above (i.e., higher than) that in the Minnelusa by approximately 35 feet at this location. These data indicate that if a conduit for flow existed (which certainly does not up to the Dewey Fault or there would be little head difference), flow would be from the Madison into the Minnelusa.

						Powertech requests removal of the permit condition in Part II, Section F.2.c and removal of language in the draft permit and fact sheet indicating that either oil and gas test wells or the Dewey Fault act as a conduit between the Minnelusa and overlying or underlying aquifers.
17	14	II.F.3.a	29	Sec. 4.4.2.2	R, C	**Comment:** There is no explanation or evidence for the 1,000-foot offset restriction around the pre-existing offset area surrounding plugged oil and gas wells. Powertech has already (conservatively) requested an offset from those wells, even though plugging records clearly indicate that wells are property plugged. There is no basis for EPA to add another 1,000 feet to the offset requested in the permit application. Because of records to the contrary, the Earl Darrow #1 well does not serve as a potential conduit for flow, and there are no other oil and gas test wells penetrating the Minnelusa or deeper in the project area. Requested Change: Powertech requests removing the 1,000-foot offset requirement as shown below. **II.F.3. Calculation of Maximum Injection Rate for Each Class V Injection Well** a. After the Permittee has calculated the critical pressure rise for each injection zone and the injection-induced injection zone pressure according to distance from each injection well using the injection rate needed to dispose of the maximum volume of treated ISR waste fluids and 10~~2~~ years of injection activity, the Permittee shall calculate a maximum injection rate for each injection well. ~~The maximum injection rate shall be determined such that the critical pressure in each injection zone is not exceeded 1,000 feet away from the nearest potential breech in confining zones, as discussed in Sections 4.4.2, 5.4.3 and 7.7.2 of the Class V Area Permit Fact Sheet.~~ This maximum injection rate shall ensure that no injection zone fluids move out of the injection zone through a pathway through the confining zones.
18	14	II.H.1	~~~	~~~	I	**Comment:** For consistency with regulatory requirements and for internal consistency, references to EPA or EPA Region 8 program should be changed to "the Director" wherever reference is made to EPA in its role as UIC program Director. Requested Change: II.H. Initial Demonstration of Mechanical Integrity 1. Prior Notification Requirement Before conducting the initial mechanical integrity tests on each Class V injection well, the Permittee shall notify the ~~EPA Region 8 UIC program~~ Director a minimum of 30 days prior to testing date to give the ~~EPA~~ Director an opportunity to witness the test.
19	14 15	II.H.3 II.I.1.g	39	Sec. 5.5.2	I, C	**Comment:** It is requested that all permit conditions reflect consistency with permit condition Part II, Section H.3, which states the Cement Bond Log shall demonstrate 80% bonding through confinement zones (as opposed to applying the requirement to all casing above the injection zone). This is supported by industry references (Fitzgerald and others; SPE Paper 12141; Exhibit 002). **Requested Change:** Requested revisions are presented below. **II.I. Evaluation of the Injection Authorization Data Package Reports for Limited Authorization to Inject** 1. The Director will evaluate the information provided in the Injection Authorization Data Package Reports and may issue a written Limited Authorization to Inject for testing purposes only. The Director will issue Limited Authorization to Inject only after finding:

						g. The well construction completion report demonstrates that each injection zone is isolated from USDWs by well casing and cement, meeting the requirements of Part III, Section D, and that there is a bond between at least 80% of the well casing and cement through confinement zones as demonstrated by the cement bond log;
20	16	I.J.4.a	36, 37	5.3.4.2	I, C, A	**Comment:** The requirement to monitor pressure within the injection zone may be problematic if a perforated interval were near the top of the injection zone, as it is ill advised to run tools below perforations. **Requested Change:** Change the permit language to allow for monitoring pressure within 50 feet of the top of the injection zone. This will allow for suspension of downhole gauges above perforations to mitigate risk of tool loss in the well. The requested change is shown below. **II.J.4. Step Rate Test and Determination of Maximum Allowable Injection Pressure** **a. Fracture Pressure:** The Permittee shall run an injection Step Rate Test for each well to determine the site-specific pressure at which fractures form in the injection zone at each injection well location. During the Step Rate Test, the Permittee shall monitor pressure within 50 feet of the top of the injection zone, as well as surface injection pressure. The Step Rate Test results shall be submitted to the Director for evaluation.
21	16 24 25 25 25 25 26 28-29 29 29 30 36 37 38 40 43 45 46	II.I.4.c III.H.2 III.J.2 III.J.2.e III.J.3 III.J.5 III.L.3 V.A.1 V.B.2 V.B.3 V.C.5.a V.E.3 Table 18 VI.A VII.C VII.D.11 VIII.A.2 VIII.J	~~~	~~~	I	**Comment:** For consistency with regulatory requirements and for internal consistency, references to EPA or EPA Region 8 program should be changed to "the Director" wherever reference is made to EPA in its role as UIC program Director. Requested Changes: - Page 16, Part II, Sec. I.4.c: "The MAIP permit limit for each injection well will be included in the Authorization to Commence Injection approval document issued by the Director~~EPA~~. - Page 24, Part III, Sec. H.2: "The Permittee shall submit to the Director~~EPA~~ an as-built final wellhead schematic diagram as part of the well construction completion report. - Page 25, Part III, Sec. J.2: "Prior to constructing an additional well under this Area Permit, the Permittee shall seek authorization to construct by submitting the following materials to the Director~~EPA~~:" - Page 25, Part III, Sec. J.2.e: "a list of all wells penetrating the Confining Zone within the Area of Review (AOR) of the new well including cementing records and cement bond logs any new wells within the AOR not previously evaluated by the Director~~EPA~~."

~ Page 25, Part III, Sec. J.3: "Once the Director~~EPA~~ has confirmed that the proposed injection well meets permit conditions, the Director~~EPA~~ Region 8 will authorize construction by written communication to the Permittee."
~ Page 25, Part III, Sec. J.5: "The Permittee shall construct a requested injection well within one year of the Director~~EPA~~ construction authorization date as described in Section K."
~ Page 26, Part III, Sec. L.3: "...and shall provide this and any other record of well workover, logging, or test data to the Director~~EPA~~ in the next Quarterly Monitoring Report."
~ Page 28-29, Part V, Sec. A.1: "The falloff testing report should be submitted to the Director~~EPA~~ no later than 60 days following the test. Failure to submit a falloff test report will be considered a violation of the Area Permit and may result in an enforcement action. Any exceptions should be approved by the Director~~EPA~~ prior to conducting the test."
~ Page 29, Part V, Sec. B.2: "... the Permittee shall immediately cease injection and report to the DirectorEPA within twenty-four (24) hours according to Part VII, Section D.11.e of this permit. Injection shall not resume until the Permittee has obtained approval to recommence injection from the DirectorEPA."
~ Page 29, Part V, Sec. B.3: "For any seismic event occurring between two and fifty miles of the permit boundary, that event will be recorded and reported to the DirectorEPA on a quarterly basis."

22 16

17 Comment:

The permit requirement limits Part II MIT logging to Radioactive Tracer (RAT) logs. Few vendors run RAT logs, and it may be difficult for those vendors to get a license to bring RAT tools into South Dakota. Temperature logs should also be considered.

Requested Change:

EPA Guidance No. 37 indicates that Part II MIT may be demonstrated by cement bond log showing 80% bond through an appropriate interval, or radioactive tracer survey, or temperature survey. Further, 40 CFR § 146.8 (general UIC) clearly indicates that a temperature log alone may be used. It states that other or alternate tests may be allowed by the Director/Administrator or may be required if the results are unsatisfactory. Powertech is committed to running a cement bond log and a temperature log to demonstrate Part II MIT. This process is commonly used on Class I wells in EPA Region 8 pursuant to 40 CFR § 146.14(b). Powertech requests the following change to provide flexibility in the event that RAT tools cannot be located.

Table 10. Formation Testing Involving Injection

TYPE OF TEST	PURPOSE
Step Rate Test	Initial test to determine site specific fracture gradient and fracture pressure to use for calculating MAIP permit limit for each well. Injection pressures shall be monitored at surface and bottom hole to determine friction loss for each well.
Initial Radioactive Tracer Survey or Temperature Log	Baseline assessment of ability of the cement behind the longstring casing to prevent movement of injected fluids out of the approved injection formation.

II.J.2. Initial Radioactive Tracer Survey or Temperature Log

a. After the Step Rate Test has been run to identify injection zone fracture pressure, the Permittee shall conduct an initial radioactive tracer survey or temperature log for each injection well while injecting at a pressure below the injection zone fracture pressure but not below the MAIP permit limit.

23	19-20	III.B Table 11 Figures 3-4	43	Table 16	I, C

Comment:

The DW No. 1 Alternate surface casing and cement interval in Table 11 are inconsistent with Figure 4.

Requested Change:

Surface casing in the table should be corrected to an approximate depth of 970 feet as shown below. Also, as described in comments #4 and #11, Powertech requests removal of Figure 3 and its listing in Table 11.

Table 11. Well Casing and Cement Summary

	Burdock		Dewey
	~~DW No.1 (Figure 3)~~	DW No.1 ~~alternate~~ (Figure 4)	DW No.3 (Figure 5)
Conductor Casing (in)	~~13 3/8"~~	13 3/8"	13 3/8"
Depth (ft)	~~60'~~	60'	60'
Surface Hole (in)	~~12 1/4"~~	12 1/4"	12 1/4"
Depth (ft)	~~Top of Minnelusa (~1,615')~~	50' below base of Sundance aquifer (~970~~1,615~~')	50' below base of Sundance aquifer (~1,305')
Surface Casing (in)	~~9 5/8"~~	9 5/8"	9 5/8"
Cement Interval (ft)	~~From top of Minnelusa to surface (0' - ~1,615')~~	From 50' below base of Sundance aquifer to surface	From 50' below base of Sundance aquifer to surface
		(0 - ~970~~1,615~~')	(0 - ~1,305')
Longstring Hole (in)	~~8 1/2"~~	8 1/2"	8 1/2"
Depth (ft)	~~Near base of Minnelusa (~2,765')~~	Up to ~250' below base of Minnelusa Porosity injection zone (~2,455')	Up to ~250' below base of Minnelusa Porosity injection zone (~2,790')
Longstring Casing (in)	~~7"~~	5 1/2"	5 1/2"
Cement volume	~~120% of calculated volume between exterior of casing and surrounding annulus.~~	120% of calculated volume between exterior of casing and surrounding annulus.	120% of calculated volume between exterior of casing and surrounding annulus.
Cement Interval (ft)	~~From base of Minnelusa to surface (0' - < ~2,765')~~	Up to ~250' below base of Minnelusa Porosity injection zone to surface (0' - ~2,455')	From ~250' below base of Minnelusa Porosity injection zone to surface (0' - ~2,790')
Open Hole (ft)	~~6 1/4"~~	n/a	n/a
Total Depth (ft)	~~At Precambrian basement (~3,195')~~	Up to 250' below base of Minnelusa Porosity injection zone (~2,455')	Up to 250' below base of Minnelusa Porosity injection zone (~2,790')

24	19	III.B	41 42	6.0 6.1	I, A	**Comment:** The permit does not provide for reasonable and expected, normal, minor changes in well construction. Due to potential conditions in the field and minor variations in geology at different locations, it is not possible to dictate exact intervals and casing depths, packer depth, tubing depth, or perforations before a well is drilled. As such, some flexibility is required for well construction. This type of flexibility is common for Class V and Class I wells regulated by EPA and various states. In addition, as described in comment #6, Powertech may use 7" or similar production casing as dictated by technical and design requirements and market conditions. Requested Change: Add a statement in Part III, Section B as follows: PART III. WELL CONSTRUCTION REQUIREMENTS B. Approved Well Construction Plans The details of the approved well construction plans are summarized in Table 11 and Figures 3 or 4 and 5. It is understood that minor changes in well construction may be necessary and are customary. The permittee has the flexibility to make such changes during well construction as warranted as long as the resulting Class V well construction is consistent with Federal UIC regulations and Part III of this permit. Allowable changes include, but are not limited to, use of 7-inch (or similar) production casing.
25	23	III.D	~~~	~~~	I,C	Comment: Depth intervals discussed in this section are inconsistent with other sections of the draft permit and should be indicated as approximate for the reasons discussed in the previous comment. Part III, Section D.5 discusses cementing from ~200 feet below base of Minnelusa porosity zone. This is inconsistent with other parts of the draft permit, which indicate that wells may be drilled up to 250 feet below this zone. **Requested Change:** The following changes are requested to make the draft permit internally consistent and to provide some flexibility during well construction. Throughout the permit, Powertech requests changing specific depths to "approximately" to allow for minor changes in the field without requiring a minor modification or approval from EPA (for example, Part III, Sec. D.3 shown below). Powertech requests removing Sections D.6.c and D.7, since field conditions will dictate cement volumes and casing centralizer spacing. It is inappropriate for EPA to specify these construction specifications, since Powertech will demonstrate Part II MIT in accordance with the permit and UIC regulations. **III.D. Casing and Cement** 3. The surface casing shall extend to approximately 50 feet below the lowermost USDW intersected by the well and must be cemented by recirculating the cement to the surface from a point approximately 50 feet below the lowermost USDW intersected by the well. 4. The Permittee shall isolate all USDWs by placing cement between the outermost casing and the well bore; 5. The Permittee shall isolate the injection zone by placing sufficient cement to fill the calculated space between the casing and the well bore: a. For DW No. 1: ~~from base of Minnelusa Formation to surface (if drilled to top of Precambrian Basement) or~~ from ~25~~0~~0' below base of Minnelusa porosity injection zone to surface, depending on drill hole depth; and

						b. For DW No. 3: from ~25~~0~~0’ below base of Minnelusa porosity injection zone to surface, depending on drill hole depth. 6. The Permittee shall use cement: a. Of sufficient quantity and quality to withstand the maximum operating pressure; and b. Which is resistant to deterioration from formation and injection fluids ~~; and~~ ~~c. In a quantity no less than 120% of the calculated volume necessary to cement off a zone.~~ ~~7. A float shoe shall be used with a float collar one or two joints up from the bottom of the casing and centralizers shall be placed at a minimum of one on every fifth casing joint.~~
26	24	III.H.1	~~~	~~~	I,C	**Comment:** A stab fitting or threaded fitting are both suitable. See comment #24 for more detailed discussion on Powertech’s request for more flexibility during well construction. Requested Change: Powertech requests the following change: **H. Sampling and Monitoring Devices** 1. The Permittee shall install and maintain in good operating condition at the wellhead: c. One-half (1/2) inch stab or threaded fittings, isolated by shut-off valves and located at the wellhead at a conveniently accessible location, for the attachment of a pressure gauge capable of monitoring pressures ranging from normal operating pressures up to at least 500 psi above the Maximum Allowable Injection Pressure (MAIP) specified in Part IV, Section H: i. on the injection tubing; and ii. on the tubing-casing annulus;
27	25	III.K	7	2.0	I,E	**Comment:** The draft permit does not clearly state that “additional wells” would be wells after the first four wells authorized by this permit are installed (e.g., Sec. K.1, K.2). There should be no time requirement for well construction, either for the initial wells (DW No. 1-4) or “additional” wells. The proposed requirements do not seem to consider that there are a number of permits and regulatory approvals needed prior to construction, including State of South Dakota hearings and additional Section 106 NHPA consultation required under the NRC license. Additionally, economic factors outside of Powertech’s control may contribute to a delay in the onset of construction. **Requested Change:** Recognizing that EPA’s primary concern is that additional wells could be constructed in the project vicinity prior to operations, Powertech proposes to replace the requirement to commence construction within a specified timeline with a requirement to present an annual Area of Review (AOR) update to EPA until construction commences. The AOR update will include an annual review of wells drilled within the AOR (well name/API or DENR number; depth; completed interval; well construction information; evidence that USDWs were isolated and, if the well is deep enough, that the Minnelusa injection zone was isolated). This type of AOR update will provide EPA with information to assure that there are no new AOR issues (potential pathways for flow from the injection zone to a USDW) that have occurred since issuance of the permit. This approach has been used successfully for years by the TCEQ in Texas for regulation of Class V and Class I (radioactive waste) UIC wells. This and other requested changes to address these comments are provided below.

						III.K. Postponement of Construction 1. The Permittee shall present an annual Area of Review (AOR) update to the EPA until construction of the Class V injection wells commences. The AOR update shall include identifying the location, depth, completion interval, and, if applicable, evidence that the Minnelusa injection zone was isolated for any new wells within the permit area ~~commence construction of at least one of the originally proposed Class V injection wells within one year of the Effective Date of the Permit. Authorization to construct and operate shall expire if construction of at least one of the originally proposed Class V injection wells has not commenced within one year of the Effective Date of the Permit, unless the Permittee has notified the Director and requested an extension prior to expiration. Notification shall be in writing, shall state the reasons for the delay and shall provide an estimated date for which well construction will commence. Once Authorization has expired under this part, the complete permit process including opportunity for public comment shall be required before Authorization to construct and operate can be reissued.~~ 2. To obtain authorization for additional wells beyond the four wells authorized by this Area Permit for injection into the Minnelusa injection zone, the Permittee shall follow the permit requirements under Part II of this Area Permit. ~~3. If an additional well is added to this Area Permit, the Permittee shall commence construction of the well within one year of authorization of the additional well. Authorization for construction of the additional well expires after one year from date of issuance, unless the Permittee has notified the Director and requested an extension prior to expiration.~~ ~~4. After the authorization for well construction has expired, the Permittee shall reapply for authorization to construct an additional well according to the procedures listed in Section J of this Part.~~
28	26 27	III.L.4 IV.F.3	45	7.3	1,C	**Comment:** The Draft permit states that minor modifications, such as adding perforations within the already approved injection zone, would be a major modification. This is an overly restrictive condition. It is common for many UIC well classes that perforations are added within the approved injection zone due to physical plugging, friction loss, or additional porosity discovered through data analysis. In all these examples, additional perforations would help inject more fluid at a lower injection pressure but would not affect fluid containment described in the permit application or specified in the Permit. There is no requirement in 40 CFR 144 or 146 to conduct MIT after adding additional perforations assuming the packer and tubing are not removed. If tubing and packer were removed to add perforations, Part I MIT would be necessary once the tubing and packer were replaced. **Requested Change:** Powertech requests the following changes. **III.L. Workovers and Alterations** 4. Any modification to well construction that is substantially different from the approved well construction plan is allowed only as a major modification of this Area Permit according to 40 CFR § 144.39 and § 124.5.

						IV.F. Approved Injection Zone and Perforations 3. Additional injection perforations may be added once the following requirements are met: a. The new perforations remain within the approved injection zone, b. The top perforation is no higher than the approved top of the injection zone ~~c. The Permittee has received approval from the Director as a major modification of this Permit in accordance with Part III, Section C.2 of this Permit; and~~ ~~d. The Director approves the addition of perforations as a major modification of this Area Permit according to 40 CFR § 144.39 and § 124.5.~~ ce. After the addition of perforations, the Permittee shall follow the requirements for well Workovers and Alterations under Part III, Section L if the tubing and packer are removed to add the perforations.
29	28	IV.K.1	50	7.8	I,C	**Comment:** There are several waste streams identified in the Waste Analysis Plan included with the permit application that are not included in the list of waste fluids in the draft permit (e.g., restoration bleed [whether or not it is processed through RO], yellowcake wash water, bleed from effluent and precipitation circuits, sumps, membrane cleaning solutions, groundwater sweep solutions, and plant washdown water). **Requested Change:** Powertech requests adding the waste streams above, which were included in the permit application, to the permit text. All of these fall into the category of waste fluids generated by the ISR process, which is already described in the draft permit. **IV.K. Approved Injectate** 1. Injection fluid is limited to waste fluids from the ISR process generated by the Dewey-Burdock Project. These waste fluids include groundwater produced from well construction, laboratory waste fluids, well field production bleed, ~~and~~ concentrated brine generated from the reverse osmosis treatment of groundwater produced from wellfield during groundwater restoration, restoration bleed not processed by reverse osmosis, yellowcake wash water, bleed from effluent and precipitation circuits, sumps, membrane cleaning solutions, groundwater sweep solutions, and plant washdown water. The groundwater pumped from any portion of the Inyan Kara aquifers for the purpose of remediating an excursion is also approved for injection into the ~~Class V~~ Class V injection wells.
30	29 34-35	V.B.2 Tables 17A and 17F	52-55 56	8.1.2.1 8.1.2.2	I, C	Comment: The draft permit has overly restrictive language related to change of operations if seismic events occur. Because low-frequency seismic events (e.g., <2.0 magnitude [MMI scale]) can occur regularly, the reference to "any" seismic event could preclude operations entirely for many days. Except for the BOR Paradox permit, where injection above fracture pressure is specifically authorized by EPA, a seismic monitoring requirement and associated operations limitation is uncommon for Class V permits. Likewise, it is uncommon for Class I permits, except for the City of Sterling wells despite the fact that there was little if any seismic risk. We are not aware of any historical induced seismic event from a Class V well operated below fracture pressure. Further, information provided in the permit application (Figures F-3 and F-4) shows that the project site is located in an area of low seismic risk, so there is not an existing concern regarding seismic issues.

Requested Change:
The requested changes shown below are similar to the Stop Light approach successfully employed by the Colorado Oil and Gas Conservation Commission (COGCC) (Exhibit 003). For example, the Exhibit 003 approach dictates response levels as follows:
Green Light – Continue operations (<M2.5 ([MMI scale] within 2.5 mi)
Yellow Light – Modify operations (>M2.5 & < 4.4 within 2.5 mi)
Red Light – Suspend operations (> M4.5 within 2 mi)
B. Seismicity
2. For any seismic event with greater than 4.5 magnitude (MMI scale) reported within two miles of the permit boundary, the Permittee shall immediately cease injection and report to EPA within twenty-four (24) hours according to Part VII, Section D.11.e of this permit. Injection shall not resume until the Permittee has obtained approval to recommence injection from the EPA.

Table 17. Monitoring, Recording and Reporting Requirements for Well Operating Parameters

A. CONTINUOUS MONITORING	
MONITOR	~~Seismic events with greater than 2.0 magnitude (MMI scale) within a two (2) mile radius of the Area Permit boundary, gathered from USGS Earthquake Hazard Program website or through personal communication.~~

Table 17. Monitoring, Recording and Reporting Requirements for Well Operating Parameters

F. QUARTERLY MONITORING	
REPORT	~~Summary of monthly reviews of seismic events with greater than 2.0 magnitude (MMI scale) within a fifty (50) mile radius of the Area Permit boundary.~~

31	30	.C.6.b	~~~	~~~	C,A

Comment:
The Draft permit states that “USEPA certified” gauge should be used for annuls pressure test. Powertech is not aware of such a certification program. As in EPA regions across the country (including Region 8), a digital pressure gauge, which is calibrated annually using a deadweight tester, will be used and certification will be provided in testing reports.
Requested Change:
Change to “calibrated and certified” gauge as shown below.
V.C.6. Mechanical Integrity Test Methods and Criteria
b. Internal Mechanical Integrity: TCA Pressure Mechanical Integrity Test Procedure
The Permittee shall conduct the following internal mechanical integrity test to verify there are no leaks in the well tubing, casing or packer.
iv. Install ~~USEPA~~ calibrated and certified gauge on "bleed" type valve. The annulus may need to be pressurized and bled off several times to ensure an absence of air.

32	31	V.D.1.b-c	~~~	~~~	R,A

Comment:
The low-flow sampling requirement is not applicable to this type of Class V well. Sampling methods specified in Part V, Section D.1.b and c are inconsistent with deep injection wells and oil/gas equipment that will be required to install the wells. The requirement for fluid sampling by swabbing 3 volumes during drilling and producing fluid via submersible pump should be removed.
Requested Change:
Sampling will be conducted “as appropriate given the tools available,” commonly by swabbing or drill stem testing (DSTs). See comment #9 for anticipated sampling procedures for the Minnelusa.

In the case of a drill stem test (DST) that might be used to sample the Sundance/Unkpapa, a packer or packers would be used on the end of the drill string to seal around or above the zone to be sampled. A valve in the bottom hole assembly would be opened allowing formation fluid to fill the drill pipe to a level dependent on reservoir pressure. The pipe would be tripped out of the hole, and formation fluid would be sampled at surface. This is an often used and viable option for collecting reservoir data and fluid samples. Assuming the formation has reasonable porosity and permeability, sufficient fluid will be produced such that wellbore fluid (mud), mud filtrate, and formation fluid are all recovered by the DST. The formation fluid will be the last fluid recovered and will be present in the bottom of the testing string and in the fluid sampling chamber (typically 1-2 gallons of volume). Fluid samples will be transferred from the sample chamber, and if necessary, the first joint of drill pipe above the sample chamber, into the sample bottles that are then sent to the laboratory for analysis.

Requested changes are shown below.

V.D. Monitoring Methods, Parameters and Frequency

1. Monitoring Methods

a. Monitoring observations, measurements, samples, etc. taken for the purpose of complying with these requirements shall be representative of the activity or condition being monitored.

~~b. During drilling, before an aquifer fluid sample is collected for laboratory analysis, the formation shall be swabbed a minimum of three times~~.

~~b~~c. Aquifer fluid shall be produced from the well using methods appropriate given the tools available ~~a submersible pump, swabbing or wireline testing equipment~~. Aquifer fluid sampling shall occur after the open-hole section has been drilled, but prior to conducting any injection testing. ~~The submersible pump is the preferred method to be used and shall be used, if possible. If a submersible pump is able to be used, the Permittee shall use the Standard Operating Procedure for Low-Stress (Low Flow) / Minimal Drawdown Ground-Water Sample Collection and measure the f~~Field parameters listed in Table 14 shall be measured at the surface as fluid is ~~pumped out of~~ withdrawn from the well to determine when collection of a representative sample is possible. When the field parameters meet the stabilization criteria in Table 14, indicating that the water quality indicator parameters have stabilized, then sample collection can take place.

33	32	V.D.1 Table 14 V.D.1.f-i	~~~	~~~	I, R, C	**Comment:** The NRC license requires analysis of three field parameters (pH, specific conductance and temperature) during monitor well sampling. The approved NRC license application also specifies a stability criterion of 10% for each of these constituents. For consistency with the NRC license, Powertech suggests changing Table 14 to list these three constituents along with the 10% stabilization criterion for each. These are reliable indicators of formation fluid and are much more stable than ORP, turbidity, or DO. Analysis of ORP, turbidity and dissolved oxygen are not included in the NRC license requirements. Powertech requests omitting these constituents from Table 14 for that reason and since these constituents are not common indicator parameters for the relatively deep, bedrock aquifers that will be monitored. For example, the EPA guidance document cited under Part V, Sec. D.1.c indicates that “Oxidation-reduction potential may not always be an appropriate stabilization parameter.” ORP, turbidity and dissolved oxygen are appropriate for surface water or shallow groundwater sampling where the water would be expected to have seasonal variation in turbidity levels and varying dissolved oxygen and ORP concentrations. They are not appropriate for deep bedrock aquifers where oxygen is absent and turbidity is only related to well development and does not affect dissolved constituent concentrations.

Powertech also requests modifying Part V, Sections D.1.f, h and i for flexibility as shown below.
Requested Changes:
Following are the suggested revisions to Table 14 and Part V, Section D.1.f.

Table 14. Field Parameters to be Monitored and Stabilization Criteria to Meet before Sample Collection

Parameter	Stabilization Criteria
pH	± ~~0.1~~ 10% pH units
Specific conductance	± ~~3~~10% µS/cm
Temperature	± 10% °C
~~Oxidation-reduction potential~~	~~± 10 millivolts~~
~~Turbidity~~	~~± 10 % NTUs when turbidity is greater than 10 NTUs~~
~~Dissolved oxygen~~	~~± 0.3 milligrams per liter~~

V.D. Monitoring Methods, Parameters and Frequency
1. Monitoring Methods
f. Injection pressure, annulus pressure, injection rate, and cumulative injected volumes shall be observed and recorded under normal operating conditions, and all parameters shall be observed ~~simultaneously~~ at the same general time to provide a clear depiction of well operation.
g. Pressures are to be measured in pounds per square inch (psi).
h. Fluid volumes are to be measured in standard oilfield barrels (bbl) or gallons (gal).
i. Fluid rates are to be measured in barrels per day (bbl/day) or gallons per minute (gpm).

34	36	V.E.2	4	1.0	I, E

Comment:
Powertech is uncertain why 40 CFR part 146 subpart G regulations are referenced as those regulations refer to Class I hazardous waste injection wells.
Requested Clarification:
Please explain the basis for reference to 40 CFR part 146 subpart G, which pertains to Class I hazardous waste injection wells. This permit is not for a Class I hazardous waste injection well, and permit conditions prohibit injection of hazardous waste.

35	37-38	V.G	44 58	6.5, 8.1.5	I, C

Comment:
Powertech will operate a manned facility. Why are there automated monitoring and shut-off requirements that would apply whether the facility is manned or unmanned? In addition, the monitoring requirements in Part V, Section G.6.h through k apply regardless of manned or remote operations.
Requested Change:
Powertech requested the addition of a qualifier to indicate that automatic monitoring guidelines must be followed only if the facility is unmanned. In addition, Powertech requests moving the requirements in Part V, Section G.6.h through k to Part V, Section D.4 (Page 36).

36	38	VI.A	~~~	~~~	I, R

Comment:
This requirement prohibits Powertech from plugging and abandoning any Class V deep injection well until after receiving written authorization from the Director, who will not approve the plugging and abandonment of any Class V deep injection wells until all Class III wellfields have been decommissioned.

						Requested Change: Powertech is committed to completing groundwater restoration and understands fully that wastewater disposal capacity is a necessity to effective completion of this requirement. However, Powertech has submitted permit applications for two methods for wastewater disposal including deep well disposal and land application. Powertech's Groundwater Discharge Plan application, which requests use of land application of treated wastewater from the project, has been recommended for approval by the South Dakota DENR and is currently pending a State Hearing. Because there is a separate option for wastewater disposal, Powertech requests that EPA update this requirement accordingly to allow for the possibility that land application may provide the necessary wastewater disposal capacity for groundwater restoration and that it may be possible that no deep wells are used for this purpose. Requested changes are provided below. **Requested Change:** Powertech is committed to completing groundwater restoration and understands fully that wastewater disposal capacity is a necessity to effective completion of this requirement. However, Powertech has submitted permit applications for two methods for wastewater disposal including deep well disposal and land application. Powertech's Groundwater Discharge Plan application, which requests use of land application of treated wastewater from the project, has been recommended for approval by the South Dakota DENR and is currently pending a State Hearing. Because there is a separate option for wastewater disposal, Powertech requests that EPA update this requirement accordingly to allow for the possibility that land application may provide the necessary wastewater disposal capacity for groundwater restoration and that it may be possible that no deep wells are used for this purpose. Requested changes are provided below. **PART VI. PLUGGING AND ABANDONMENT** A. Requirement for EPA Approval before Plugging and Abandonment of Class V Deep Injection Wells The Permittee shall not commence plugging and abandonment of a Class V Deep injection well until after receiving written authorization from the Director. The Director will not approve the plugging and abandonment of all~~any~~ Class V deep injection wells until all Class III wellfields have been decommissioned by the NRC unless land application or another alternate method of disposing treated wastewater is available. At least one Class V deep injection well shall remain active or temporarily abandoned until all Class III wellfields have been decommissioned unless land application or another alternate method of disposing treated wastewater is available.
37	44	VII.D.11.i	~~~	~~~	R	**Comment:** Suggest not using the "NRC" acronym for National Response Center, since it is used elsewhere in the document for U.S. Nuclear Regulatory Commission.
38	45	VIII.A.1	~~~	~~~	E	**Comment:** Specifically, what is meant by "EPA's model language" with respect to the various acceptable forms of financial assurance? **Requested Change:** Powertech requests clarification of "EPA's model language."
39	46	VIII.J	61	10.2	I, A	**Comment:** The proposed provision would require an updated financial responsibility cost estimate to be submitted within 21 days of the Effective Date of the Final Permit and a demonstration of financial responsibility within 30 calendar days of the Effective Date of the Final Permit. As described in comment #27, there are a number of permits and regulatory approvals needed prior to construction, and economic factors may contribute to a delay in the onset of construction.

Requested Change:

Powertech proposes to provide EPA with an updated financial responsibility cost estimate at least 90 days prior to initial construction of any Class V injection wells within the permit area. This is consistent with License Condition (LC) 9.5 in NRC license SUA-1600, which requires Powertech to provide an updated financial assurance estimate at least 90 days prior to beginning construction activities associated with any planned expansion or operational change that was not included in an annual financial assurance update (Exhibit 004 at 3-4). Powertech proposes to provide EPA with demonstration of financial responsibility at least 90 days prior to commencing Class V injection well operations. This is also consistent with LC 9.5, which requires Powertech to submit the financial assurance instrument for NRC staff review and approval 90 days prior to commencing operations. Requested changes are shown below.

VIII.J. Updated Cost Estimate and Timing for Demonstration of Financial Responsibility

An updated cost estimate shall be submitted at least 90 days prior to construction of any Class V injection well within the permit area~~within 21 days of the Effective Date of the Final Permit~~. The demonstration of financial responsibility shall be submitted to the Director~~EPA~~ at least 90 days ~~within 30 calendar days of the Effective Date of the Final Permit and~~ before the commencement of operation of any Class V injection well ~~construction activities~~. Any well ~~construction~~ operational activities are prohibited until financial responsibility has been approved by the Director~~EPA~~.

40	48	App. A Fig. A-1	~~~	~~~	I, A	**Comment:** Appendix A, Figure A-1 Preliminary Wellhead Schematic depicts an impractical tree configuration which in inconsistent with the permit application and industry standards. **Requested Change:** Powertech requests that the attached proposed wellhead schematic (Exhibit 005) replace that in the draft permit as it satisfies all capabilities for monitoring and sampling requirements.

Comment type key:
A – alternate approach proposed;
C – correct to be consistent with application, regulations or NRC license requirements;

E – additional explanation requested;
I – inconsistency (internally inconsistent between parts of Draft permit or supporting documents);
R – remove; inconsistent with application, regulations or NRC license requirements;
T – typographical error

the addition of "and if constructed" is discussed under comment 11

Ex. 5 Deliberative Process (DP)

Ex. 5 Deliberative Process (DP)

PURPOSE	DUE DATE
For laboratory testing to determine the porosity, effective porosity and permeability of the injection zone.	Prior to receiving ~~Limited~~ Authorization to Inject
For laboratory testing to determine the permeability and hydraulic conductivity of the overlying confining zone.	Prior to receiving ~~Limited~~ Authorization to Inject

For laboratory testing to determine the permeability and hydraulic conductivity of the underlying confining zone.	Prior to receiving ~~Limited~~ Authorization to Inject

Ex. 5 Deliberative Process (DP)

Ex. 5 Deliberative Process (DP)

Chilson Wells
2, 13, 16, 42, 615, 619, 633, 650, 680, 696, 697, 705, 3026, 7002
Fall River Wells
Wells 5, 7, 8, 18, 628, 631, 681, 688, 694, 695, 698, 706
Unkpapa Wells
690, 693, 703, 704

Ex. 5 Deliberative Process (DP)

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Ex. 5 Deliberative Process (DP)

Ex. 5 Deliberative Process (DP)

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Ex. 5 Deliberative Process (DP)

Ex. 5 Deliberative Process (DP)

Ex. 5 Deliberative Process (DP)

Ex. 5 Deliberative Process (DP)

See 3.2.12 Instrumentation and Control in Dec 2013 Tech Report

Well Operating Procedures, Alarms and Annulus Pressure Maintenance
in the Class V permit application